Via Fax To: George Dean
Company: MA Attorney General
Phone: Fax:
From: Paul Chernick
Company: Resource Insight, Inc.
Suite 1000, 18 Tremont Street, Boston MA 02108
Phone: (617)-723-1774 Fax: (617)-723-6203
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Re: Comments on Small Customer Access and the E-Plan

Small Customer Access

The Attorney General is concerned that the Department has not confronted the issue of ensuring that all customers have access to the benefits of the competitive bulk-power market. Large customers will be (or are already) fitted with real-time meters, so that the distribution company will be able to determine the amount of power that each marketer must deliver to the distribution company in each hour to serve those customers. This sophisticated metering has not been installed on any significant number of residential or small commercial customers; considering the range of competing options, the importance of the decision, and the scale of the installation task, these customers are not likely to get such meters soon.

At some point in the future, real-time metering will be available and cost-effective for all customers. In the meantime (which may be a few years, or a decade), some mechanism must be developed to ensure that every customer has access to the competitive market. If the Department fails to create such mechanisms in time for marketers to comprehend them and develop rate offering for small customers by the beginning of restructuring, those customers will be excluded from the benefits of competition.

The Attorney General believes that the Department should ensure that at least one of the following mechanisms is available to all customers:

- **Regional Aggregation:** A single marketer could serve all customers in a geographical region, such as municipality, or the area served from a substation, feeder, or other convenient metering point, other than those who opt for real-time meters and service from another aggregator. (This approach is used in the current New Hampshire pilot.) The large customers will presumably opt for individual direct access; smaller customers could do so as well, if they or their marketers are willing to pay for the incremental costs of real-time metering. The remaining customers in each area could collectively choose their marketer, through hearings or polling by their municipal governments or another agent selected by the Department. The same agent would determine the formula for allocating the regional power cost to individual bills, with Department approval. The marketer's responsibility for power delivery to each regional aggregation could be determined in real time, or with a trivial delay.

- **Individual Customer Allocation.** To increase customer choice and allow individual selection of power marketer, the distribution utility can estimate the hourly loads of each small (not real-time-metered) customer, ex post, by

1. determining total distribution system load in the hour,

2. subtracting loads of customers with real-time meters, plus estimates of associated losses,

3. allocating the monthly bill of each small customer to hours on the basis of a series of multipliers developed from load-research data, plus losses,[1] and

4. reconciling the results so that the sum of customer loads and losses equals system load.

   Appendix 1 {In preparation} provides an example of the form that the hourly multipliers might take. Each utility would need to file the loss factors and hourly allocation multipliers, along with the supporting load-research data and computations, for review and approval by the Department. The marketer's responsibility for power delivery to each customer could only be determined after the fact, when all meters have been read. Initially, this would result in a delay of a month or more between power delivery and reconciliation, although more frequent meter reading would reduce the lag.

In either of these approaches, all energy delivered to the distributor in each hour will be allocated to losses, direct-metered customers, or small customers. The marketer, not the distributor, will provide (or purchase) load-shaping, regulation, operating reserves, and other ancillary services.

In the alternative proposed by WMECo, the marketer would provide only a generic load shape of some sort, and the distributor would retain generation to provide ancillary services, including all differences between the generic load delivered by the marketers and the actual system load.[2] The Attorney General believes that this would be ill advised, for at least three reasons.

1. The distribution and generation functions should be clearly separated in restructuring, to minimize the possibility of cross subsidies. Since the ancillary services are provided by the same plants as the bulk power, abuse would be difficult to prevent.

2. The ancillary costs are difficult to determine, and no party has proposed a viable method for estimating them. WMECo's estimates of the costs of ancillary services are arbitrary allocations of power plant ratemaking costs, rather than direct computations of the costs of providing the services.

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[1] Utilities will need to read meters at least monthly for this approach to be at all viable.

[2] NEES's proposal to use "load research data" for allocation of loads may fall in this category, or may be a very vague description of Individual Customer Allocation, as discussed above.

3. Ancillary costs are as much related to the nature of the power plants as to the nature of the load. Some power marketers will be selling from power plants that provide reactive power, load following, operating reserves, black-start capability, and other functions. Others will be selling from plants that do not provide these services. The costs of the ancillary services must be therefore by borne by the marketers, probably through requirements imposed by the ISO or power exchange.[3]

Phase I Transition Rates

In DPU 96-100, the Department endorsed Boston Edison's "Phase I" proposal to implement revise rate design prior to restructuring, primarily to put the spot energy price on the bill. This would allow customers to purchase contracts for differences in the power market, and get them used to the power cost with which marketers will be competing. The Attorney General supports these objectives, if they can be achieved without excessive commitment of regulatory resources in the brief period prior to restructuring.

The Department's final rules should correct certain problems in Boston Edison's proposal:

1. Boston Edison proposed to develop a Power Market Index that would be used in determining the rates Boston Edison could charge. The Department should insist on an objective index (such as the NEPOOL dispatch margin, or a firm-power market transaction price) computed by a neutral third party (such as the power exchange, once it exists).

2. Boston Edison proposed to include an arbitrary charge for "No-Load Costs," computed for an undefined "most expensive" unit on line in any hour.[4] No-load costs are not a part of the market-clearing price. In addition, Boston Edison's method for computing no-load costs can result in extremely high costs in hours in which the "most expensive" unit is operated at a very low level.[5] This proposed charge is particularly inappropriate, since the "most expensive" unit will often be coming on line to meet load in subsequent hours (or ramping down after meeting load in earlier hours), so its startup is not determined by load in the current hour.

3. Boston Edison proposed a charge for capacity based on LOLP, which may or may not be a good approximation for the driving force of hourly or daily capacity prices in the competitive market. Marketers are just as likely to purchase capacity in advance, and charge customers a predetermined adder. LOLP is a theoretical

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[3] NEPOOL currently requires members to provide their share of reactive power and operating reserves, or pay other suppliers to do so.

[4] BECo does not state whether "most expensive" would be computed on the basis of marginal dispatch cost, no-load cost, or some other measure.

[5] See the data for hour 18 on 2/6/96 on page 64 of Boston Edison's filing of February 16, 1996.

computation, not subject to empirical verification. The Attorney General does not see any particular benefit to including this tangential and contentious variable in the short-term unbundling of utility rates.

4. The bill design proposed by Boston Edison for is unnecessarily complex and misleading:

   a. There is no point in separating distribution from transmission costs, since it is not clear what part of the costs currently in the transmission accounts will be included in the distribution charge and which will be recovered through regional transmission charges assessed by the ISO.

   b. Splitting out the DSM costs will create unnecessary conflict. Any cost specifically identified on the bill has always attracted customer animosity. There is no more reason to separate DSM costs than to separate fuel, NUG purchases, management salaries, or the extra costs due to the high O&M and low reliability of Pilgrim.

   c. As demonstrated in the Attorney General's comments of April 17, the "access" charge proposed by Boston Edison for Phase I is much higher than the stranded cost charge that might be justified in full restructuring. In Phase I, Boston Edison will not yet have mitigated stranded costs by divesting or repricing generation at the market price, including the future value of the capacity. Hence, this charge should be called "other generation costs," to avoid confusion with the much lower or negative stranded-cost charge that the Department may later approve.

   With these corrections, the bill design need only consist of four components, rather than Boston Edison's six: Customer charge, Delivery cost (T&D), Other generation costs, and Market power costs.

5. It is not clear that Boston Edison's proposed bill redesign would be revenue-neutral. The Department should demand that the redesign be revenue-neutral, prospectively and retrospectively. To ensure retrospective revenue-neutrality, any over- or under-collection can be credited or added to stranded costs.[6]

6. Boston Edison proposed that rates be set on, and revenues reconciled to, Boston Edison's projections of rising fuel and purchased power costs. Litigating future costs for all seven Massachusetts utilities would take time and resources that the Department and the parties need for the broader restructuring cases. To avoid unnecessary litigation, fuel prices should be included in the reconciliation described above.

7. Even with reconciliation, a rate proceeding will be necessary for each utility, to determine the initial estimate of market costs, the market-cost proxy, the non-market rate components, the form of the reconciliation, and projected rates and

[6] Boston Edison suggests rolling reconciliation of annual forecasts. This is strange, since the Phase I rates are only to be in place in 1997.

revenues for initial rate design and for the reconciliation.

8. Boston Edison's assertions about rate design are mostly ill-founded. This is not the time to waste effort arguing over a single-year rate design. Total rates for each billing determinant should not change in Phase I.

Appendix 1
Example of Computations Required for Allocation of Load to Individual Customers without Hourly Meters

Load Research Data: Preparing for Load Allocation

Most utilities will have load research data on hourly loads of a sample of customers in each rate class, over an extended period (typically, several years). Some utilities will have enough customers on load-research metering in various sub-classes--such as customers with monthly use under 200 kWh, or heating customers, or small retail versus small offices--to derive load shapes for those groups as well. Some utilities have modeled load as a function of weather variables--such as heating degree days (HDD), cooling degree days (CDD), or temperature-humidity index (THI)--and the others can combine readily-available historical data with existing load data, to produce an estimate of a customer's load in each hour as a function of monthly metered sales, month, day, hour, and weather:

$$MLF_{cmdhb} = a_{cmdhb} + b_{cmdhb} \times W_h$$

where

MLF = monthly load factor = $\dfrac{\text{hourly load}}{\text{monthly metered energy use}}$

c = class

m = load month (perhaps simplified to season, if the class has very similar load shapes in all months in a season)

b = billing month (the load month or the next month)

d = day type ({S, M, T…S} or {weekday, Saturday, Sunday}, with each holiday assigned to one day type

h = hour

w = weather variable (HDD, CDD, THI)

Utilities generally summarize their load research results by calendar month. Calendar month is not the relevant period for measuring monthly energy use in the monthly load factor, since this factor will be applied to the metered sales on the customer's meter-reading schedule. For example, the customer's loads on August 15 may be estimated from an August meter reading on August 15 through 31, or from a September meter reading on September 1 through 14. Computing the average MLF for bills rendered on the various days of the month should present no special problem.

For each class or sub-class of small customers (i.e., the customers who will not be fully equipped with hourly meters by 1/1/98), the utility will need to determine, file for review and approval by the Department, and then publish for potential marketers 576 to 4000 MLF equations for each class or sub-class, depending on the number of month types and day types.

The utilities will also have to generalize their loss studies, to allow them to estimate losses in each hour for a class, as a function of the customer's load (which affects mostly secondary distribution losses) and the system load (which determines transmission and most primary distribution losses, except for customers large enough to dominate loads on their feeder or substation):

$loss_c[TI, L_x]$ =

= losses for a customer x in class c, as a function of total input (TI) to the distribution system at the ISO transmission delivery points and the customer's load (L_x).

Allocating Hourly Loads under Retail Access

For each hour, the distribution utility will be able to readily determine the unmetered (that is, without real-time or hourly meters) load as

$ULI_h = TI_h -$

ULI_h = unmetered load in hour h at distribution system input

TI = total input (TI) to the distribution system at the ISO transmission delivery points

L_{hx} = load in hour h for hourly-metered customer x

From the published results of the load-research data and loss studies, the utility can construct an initial estimate of the ULI:

$XULI_h =$

S_{bx} = metered sales to customer x in billing month b for bills that include hour h of day d in month m

The final allocation to each customer without hourly metering is then

$$AL_{xh} = MLF_{cmdhb} \times S_{xb} \times (1 + loss_c[TI_h, L_{xh}]) \times \frac{ULI_h}{XULI_h}$$